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Basin-scale hydrogeologic impacts of CO_2 storage: Capacity and regulatory implications

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ABSTRACT

Industrial-scale injection of CO_2 into saline formations in sedimentary basins will cause large-scale fluid pressurization and migration of native brines, which may affect valuable groundwater resources overlying the deep sequestration aquifers. In this paper, we discuss how such basin-scale hydrogeologic impacts (1) may reduce current storage capacity estimates, and (2) can affect regulation of CO_2 storage projects. Our assessment arises from a hypothetical future carbon sequestration scenario in the Illinois Basin, which involves twenty individual CO_2 storage projects (sites) in a core injection area most suitable for long-term storage. Each project is assumed to inject five million tonnes of CO_2 per year for 50 years. A regional-scale three-dimensional simulation model was developed for the Illinois Basin that captures both the local-scale CO_2–brine flow processes and the large-scale groundwater flow patterns in response to CO_2 storage. The far-field pressure buildup predicted for this selected sequestration scenario support recent studies in that environmental concerns related to near- and far-field pressure buildup may be a limiting factor on CO_2 storage capacity. In other words, estimates of storage capacity, if solely based on the effective pore volume available for safe trapping of CO_2, may have to be revised based on assessments of pressure perturbations and their potential impacts on caprock integrity and groundwater resources. Our results suggest that (1) the area that needs to be characterized in a permitting process may comprise a very large region within the basin if reservoir pressurization is considered, and (2) permits cannot be granted on a single-site basis alone because the near- and far-field hydrogeologic response may be affected by interference between individual storage sites. We also discuss some of the challenges in making reliable predictions of large-scale hydrogeologic impacts related to CO_2 sequestration projects.

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1. Introduction

Geologic carbon sequestration (GCS) in deep formations (e.g., saline aquifers, oil and gas reservoirs, and coalbeds) has drawn increasing consideration as a promising method to mitigate CO_2 emissions and associated climate change (IPCC, 2005). The amounts of CO_2 that would need to be injected and stored underground to make a noticeable impact on atmospheric emissions are very large. Releases of anthropogenic CO_2 into the atmosphere is currently almost 30 Gt (billion metric tonnes) per year. At typical *in situ* densities of stored CO_2, the corresponding fluid volume would be about eight times larger than the current annual world oil production. This means that geologic storage of 15% of the anthropogenic CO_2 emissions would require a fluid-handling system larger than that in place for world oil production.

By far the greatest storage capacity is in saline aquifers (Dooley et al., 2004; IPCC, 2005), and our discussion will focus primarily on CO_2 storage in saline formations. Injection of CO_2 into deep saline aquifers will impact subsurface volumes much larger than the CO_2 plumes themselves. An industrial-scale CO_2 storage project for a large coal-fired power plant of 1000 MW generation capacity will generate, over a typical lifetime, a subsurface plume with linear dimensions of 10 km or more, while pressurization of more than 0.1 MPa would likely occur over basin-scale regions with dimensions of 100 km and more (Pruess et al., 2003). Such large-scale pressure changes may have environmental impacts on shallow groundwater resources, i.e., causing water table rise, increasing rates of discharge into lakes or streams, and/or mixing of displaced native brine into drinking water aquifers (Bergman and Winter, 1995). The level of impact depends mainly on the magnitude and extent of pressure buildup in a deep storage formation and the hydraulic communication with overlying freshwater aquifers (Birkholzer et al., 2009).

One scenario where freshwater aquifers could be impacted is CO_2 injection into the deep (downdip) saline part of an extensive

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formation that holds potable groundwater in its shallow updip part (Nicot, 2008). Freshwater resources may also be affected if high-permeability conduits such as conductive faults and abandoned boreholes provide local conduits for pressure perturbation and brine migration. In addition, the sealing layers that separate deep storage formations from overlying freshwater aquifers may pinch out at some distance from injection sites, have higher local breaches due to erosional channels, and/or may be degraded geomechanically because of overpressure in the storage formations. All these would allow for increased interlayer communication. Finally, land-surface deformation or uplift is expected in response to large-scale pressure increases, which may change surface and subsurface flow patterns, even without a direct hydraulic impact of brine displacement. The reverse effect, land subsidence in response to groundwater withdrawal (e.g., for water supply and agriculture) or oil production, is a common problem throughout the United States (USGS, 1999).

Concerns about large-scale pressure buildup and brine migration caused by industrial-scale CO_2 sequestration, and their possible environmental impacts, have been raised as early as in the 1990s (van der Meer, 1992; Bergman and Winter, 1995; Gunter et al., 1996). Since then, less emphasis has been placed on evaluating large-scale pressure changes and understanding the fate of native brines displaced by injected CO_2. Most research on geologic storage of CO_2 has instead focused on evaluating the hydrogeologic conditions under which the injected volumes of CO_2 can be safely stored, addressing issues such as the long-term efficiency of structural trapping of CO_2 under sealing units and the possibility of CO_2 leakage through faults and boreholes. The same focus has been seen in risk assessment efforts (e.g., Stenhouse et al., 2006; Pawar et al., 2006; Oldenburg et al., 2008, 2009; Viswanathan et al., 2008; Stauffer et al., 2009), as well as in discussions on and recommendations for regulatory and permitting frameworks. Meanwhile, estimates of regional storage capacity for CO_2 sequestration have been based on simple calculations of the fraction of total reservoir pore space available for safe trapping of CO_2 (Bradshaw et al., 2007; Bachu et al., 2007; USDOE, 2008), making the underlying assumption of "open" formations from which native brine can easily escape laterally and make room for injected CO_2. Moreover, the field experiments of CO_2 storage to date have primarily been quite small and were conducted to improve our understanding of CO_2 injectivity and migration patterns, and to test methods of monitoring and modeling of CO_2 migration (e.g., the Frio experiment as described in Hovorka et al., 2006). Because the injected fluid volumes have been so small, on the order of several thousand to several ten-thousand tonnes of CO_2, pressure buildup was not significant.

Only recently have researchers paid more attention to evaluating the large-scale pressure responses expected for future industrial-scale carbon sequestration, in part on the basis of modeling studies for hypothetical sequestration scenarios. A simulation study of CO_2 injection into compartmentalized saline formations (Zhou et al., 2008) suggests small storage capacity because strong pressurization occurs and geomechanical damage must be avoided. van der Meer and Egberts (2008) and van der Meer and Yavuz (2008) introduced the concept of "total affected space" defined as the region affected by CO_2 plume migration and brine pressurization. Both studies point out that the storage capacity in bounded reservoirs is limited by a yet-to-be-defined maximum allowable pressure increase and the compressibility of the fluids and pore space in the affected area. Birkholzer et al. (2009) modeled CO_2 migration and pressure response in an idealized, laterally open groundwater system, comprising a sequence of laterally extensive aquifers and aquitards (sealing units) that extend from the deep saline storage formation to the uppermost freshwater aquifers. Based on the results from a variety of sensitivity cases, the authors concluded that the hydraulic characteristics of sealing units strongly affect the lateral and vertical volumes affected by pressure buildup.

Nicot (2008) employed a single-phase flow model to simulate the regional-scale brine flow processes in response to hypothetical future CO_2 sequestration in the Texas Gulf Coast Basin, approximating the injection of CO_2 by adding equivalent volumes of saline water. Built on a calibrated regional-scale groundwater flow model, the single-phase flow model reasonably represents the far-field procceses and basin-scale impacts, without accounting for local two-phase CO_2–brine flow, variable density effects, and CO_2 compressibility effects (Nicot et al., 2008a). Yamamoto et al. (2009) reported on a high-performance multi-million gridblock model capable of evaluating local CO_2–brine flow processes together with large-scale groundwater patterns, applied to a possible future CO_2 storage scenario in the Tokyo Bay, Japan. The above model results suggest that the basin-scale hydrogeologic impacts related to pressure buildup and brine migration may affect the way CO_2 storage projects will be regulated. These impacts may in fact be the limiting factor determining the CO_2 sequestration capacity in large sedimentary basins.

In this paper, we elaborate on the issue of large-scale pressure buildup limitations on storage capacity and ensuing regulatory aspects, using the Illinois Basin in the midwest United States as an illustrative example. The Illinois Basin, a deep saline sedimentary basin of roughly 155,000 km^2 encompassing most of Illinois, southwestern Indiana, and western Kentucky in the United States (Fig. 1), hosts a significant number of large stationary CO_2 emitters (MGSC, 2005; NETL, 2009). If mitigation of climate change via carbon capture and storage is seriously attempted in the United States, the Illinois Basin will be one of the most important target regions for geologic storage of carbon dioxide in the United States. Extensive site characterization has been completed and a large-scale field project is ongoing to demonstrate the suitablity of the regionally extensive Mount Simon Sandstone as a storage formation. We developed a regional-scale three-dimensional (3-D) model for the Illinois Basin that captures both the local-scale CO_2–brine flow processes and the large-scale groundwater flow patterns in response to a hypothetical future carbon sequestration scenario, which involves twenty individual CO_2 storage sites in a core injection area most suitable for long-term storage.

Section 2 introduces briefly the geologic and numerical models and describes selected prediction results. A comprehensive paper with focus on the model development and detailed results is being published concurrently (Zhou et al., submitted for publication). In Section 3, the model results are used to demonstrate that CO_2 storage capacity of a given basin, estimated using the effective pore volume available for safe trapping of CO_2, might have to be revised down based on assessment of pressure buildup and its potential hydrogeologic impacts on freshwater aquifers. Section 4 discusses some of the challenges in making reliable predictions of large-scale hydrogeologic impacts of CO_2 sequestration projects and makes tentative suggestions for better understanding and constraining the processes and parameters driving brine pressurization. Section 5 finally demonstrates the importance of understanding large-scale pressure and brine migration patterns for regulating CO_2 storage projects.

While the model development is based on the best information currently available, we caution that the Illinois Basin study discussed here is preliminary, that some simplifications had to be made in the model design, and that considerable uncertainty regarding the large-scale geological model needs to be acknowledged. Further site characterization efforts are underway, and model predictions of hydrogeologic impacts may change as more details for future storage scenarios are being developed. Readers

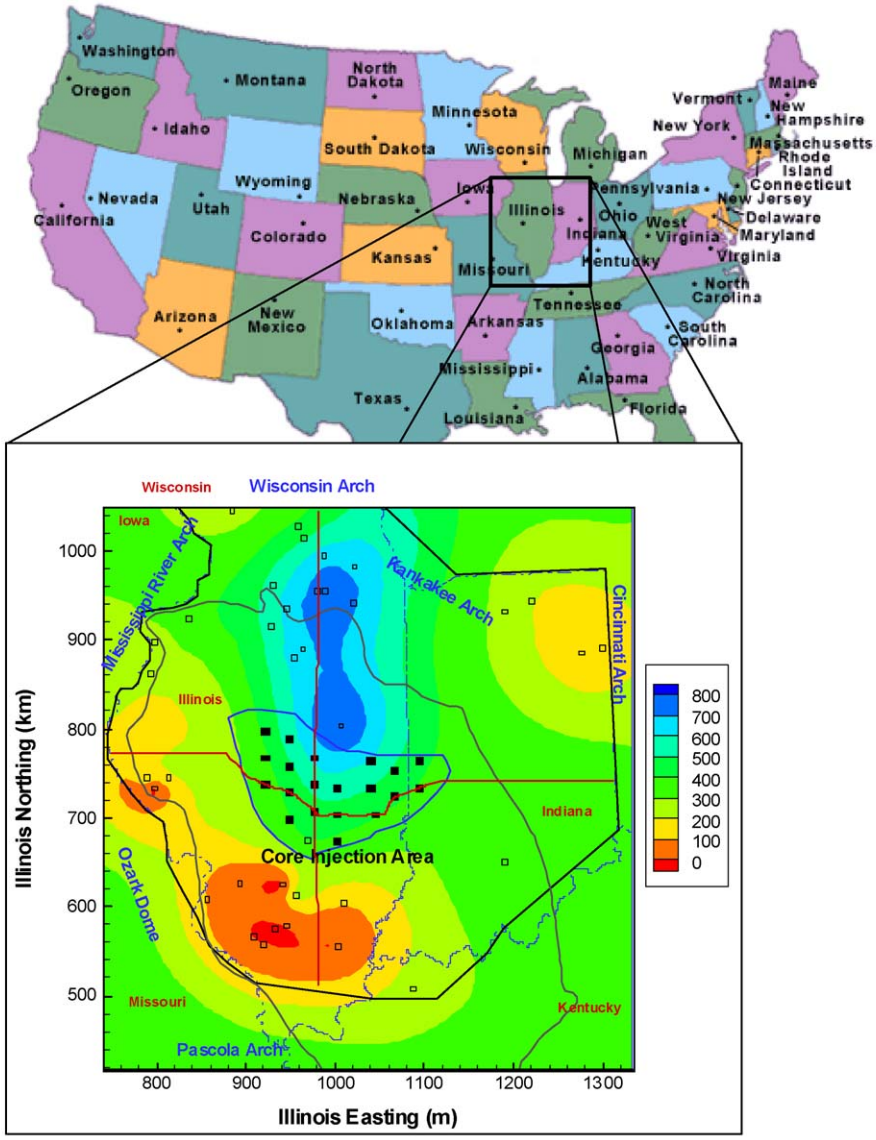

Fig. 1. Thickness of the Mount Simon Sandstone (shaded contours in m). Also shown are the boundary of the model domain as a black line, the Illinois Basin boundary as a gray line, deep boreholes used for developing the geological model as hollow squares, the core injection area as a blue line, 20 hypothetical injection sites as solid squares, and south–north and west–east cross sections (see Fig. 2) as red lines. Illinois Easting and Northing coordinates are given in km.

should view this paper as an attempt to illustrate the important implications of basin-scale impacts of CO_2 sequestration, using a realistic but not necessarily accurate example that may be representative of many other sedimentary basins worldwide.

2. Illinois Basin modeling example

The Illinois Basin region has annual CO_2 emissions of slightly over 300 Mt (million metric tonnes) from stationary sources, primarily from large coal-fired power plants (USDOE, 2008). The primary target for CO_2 storage in the region is the Mount Simon Sandstone, a deep saline aquifer of high permeability, porosity, and sufficient thickness, with proven regional seals (MGSC, 2005). With a large estimated storage capacity (USDOE, 2008), the Mount Simon Formation is expected to host multiple sequestration sites, based on the current portfolio of industrial point sources and the projected future developments.

A regional-scale simulation model was developed for the Illinois Basin region to predict the hydrogeological changes in response to a hypothetical future carbon sequestration scenario, which involves twenty individual CO_2 storage sites spaced 30 km apart in a core injection area in the center of the basin. The core injection area was selected based on favorable geological settings, sufficient thickness and depth, minimum distance to gas storage fields, and proximity to large stationary CO_2 sources. At each site, an annual injection rate of 5 Mt CO_2 was used for an injection period of 50 years. The total injected mass of 100 Mt per year represents one third of the current annual CO_2 emissions from large stationary sources in the Illinois Basin region. Over the 50 years, the cumulative CO_2 mass adds up to 5000 Mt of CO_2, which corresponds to an additional fluid volume of about 5.5 km^3 (assuming a CO_2 density of 0.9 metric tonnes/m^3) that needs to be stored in the Mount Simon Formation.

2.1. Geologic and numerical model

The model domain covers an area of roughly 570 km by 550 km (Fig. 1), a total area of 241,000 km^2 extending beyond the actual basin boundary. The domain includes the core injection area and a far-field area away from the injection sites where regional pressure changes and brine migration processes need to be assessed. With the Mount Simon Formation an open hydrogeologic system that extends far beyond the Illinois Basin area into neighboring basins, the lateral model boundaries were chosen at a large enough distance from the injection centers such that boundary effects on CO_2 plume migration and brine pressurization are small. The model domain extends north to the southern edge of the Wisconsin Arch (Fig. 1). The southwestern model boundary is formed by the Ozark Uplift in Missouri, where the Mount Simon Formation becomes thin or disappears. To the south, the model domain ends at the extensive and dense faults zones there, and to the east, it ends at the Cincinnati Arch.

In the vertical direction, the model comprises the Mount Simon Sandstone, the overlying Eau Claire sealing unit, and the upper, weathered portion of the underlying granite baserock (Fig. 2). The stratigraphic model for these formations was developed using boreholes that penetrate into the Mount Simon, half of which had been drilled down to the underlying Precambrian granite. The Mount Simon Sandstone is continuous throughout the entire Illinois Basin, except in the southern and southwestern parts of the Basin, where Precambrian highs exist and Cambrian sediments are absent. The thickness of the formation varies significantly, with a maximum of 700 m in the bowl-shaped area in the center of the basin. The top elevation of the Mount Simon Formation dips down from shallow parts in the north to more than 4000 m below the mean sea level in the south. Notice that in the south and in the center of the basin, the Mount Simon Sandstone is separated from freshwater resources by a sequence of various sealing layers and saline aquifers. In northern Illinois, however, the relatively shallow portion of the Mount Simon Formation is separated only by the Eau Claire regional seal from a valuable and heavily used freshwater aquifer, the Ironton-Galesville aquifer. Thus, there is a concern about potential degradation of freshwater resources due to pressure buildup and migration of displaced brine in response to future deployment of CO_2 sequestration in the area.

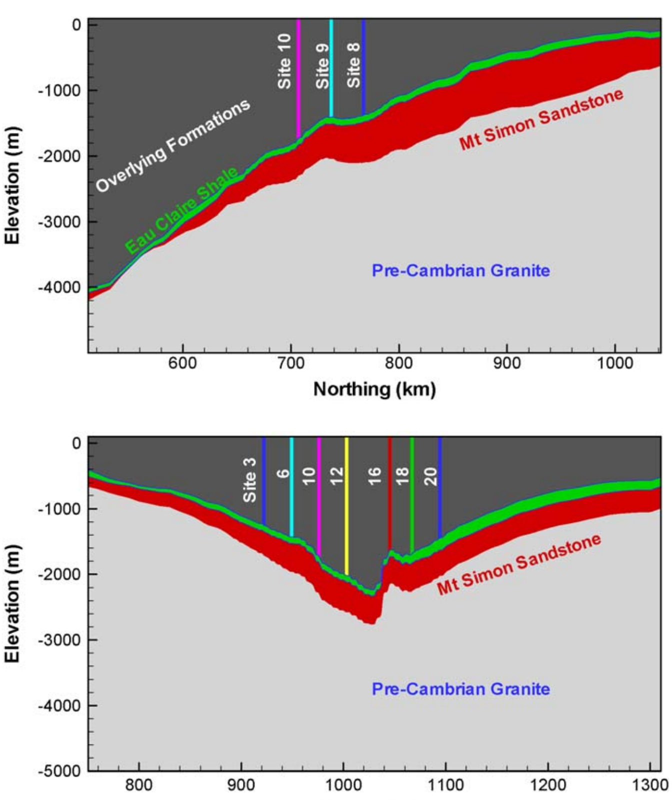

Fig. 2. North–south and east–west cross sections showing simplified stratigraphy and location of CO_2 storage sites.

A three-dimensional unstructured mesh was constructed with progressive mesh refinement in the core injection area to capture details of two-phase flow and its spatial variability, using local grid refinement down to 20 m in the horizontal and 10 m in the vertical direction in the vicinity of each injection center. The entire 3-D mesh consists of over 1.2 million grid-blocks and more than 3.7 million connections between them. The parallel version of the TOUGH2/ECO2N simulator (Pruess et al., 1999; Pruess, 2005; Zhang et al., 2008) was used to simulate simultaneously the plume-scale and basin-scale flow processes. The simulator solves for the multiphase flow and multicomponent transport of CO_2 and brine in response to CO_2 injection, under full account of the comprehensive constitutive equations for the thermodynamics of all fluids (e.g., brine density and viscosity, CO_2 density and viscosity, CO_2 solubility in brine, brine solubility in CO_2, and their dependence on fluid pressure, temperature, and salinity). Note that the simulations were conducted in isothermal mode, though temperature-dependent thermodynamics were considered based on the initial temperature field.

The formation properties and initial conditions used in the model were selected based on extensive investigation of existing literature. Most of the available information stems from natural gas storage and groundwater resources development in the area. Details on the data used and the rationale for parameter selection are provided in Zhou et al. (submitted for publication). The key formation properties relevant to large-scale pressure propagation and brine migration are permeability, porosity, and pore compressibility. Permeability and porosity values near each injection site (within a 5 km radius from the injection center) were assigned based on detailed well logs available from a small number of wells. The observed depositional variability of rock properties within the Mount Simon was incorporated into the model using 24 hydrogeologic layers.

Further away from each injection site, the model uses average values of permeability and porosity for all model layers. A uniform porosity of 0.12 and a uniform permeability of 100 millidarcy were used within the core injection zone (with the exception of the injection site vicinity). Taking into account the regional trend of increasing permeability in the shallower parts of the Mount Simon Formation, we used a permeability of 500 millidarcy and a porosity of 0.12 outside of the core injection zone (Birkholzer et al., 2008; Zhou et al., submitted for publication). The overlying Eau Claire seal has a permeability of 1 microdarcy and a porosity of 0.15. This value represents the effective regional-scale vertical permeability of a low-permeability caprock with some local imperfections (Zhou et al., submitted for publication). To evaluate sensitivity to seal permeability, we ran an alternative simulation case with a vertical permeability value of 0.01 microdarcy, based on measurements conducted on undisturbed core. The upper, weathered portion of the granite baserock, about 40 m thick, has a permeability of 0.1 microdarcy and a porosity of 0.05. This unit was included in the model because some downward migration of brine occurs in response to pressure buildup in the storage formation. In contrast, the underlying intact granite can be considered impermeable for all practical purposes.

No direct measurements of pore compressibility were available for the Mount Simon Sandstone in the region. Therefore, we back-calculated a pore compressibility value of $3.71 \times 10^{-10}\ Pa^{-1}$ based on a pumping test conducted in the Hudson natural gas storage field in 1969 (ISWS and Hittman Associates, 1973; Visocky et al., 1985). This value, quite reasonable for consolidated sandstones, was used throughout the model domain. The parameters needed to describe the CO_2–brine two-phase flow system were based on Doughty et al. (2008).

Vertical profiles of *in situ* temperature and salinity were available from several temperature and salinity logs available in

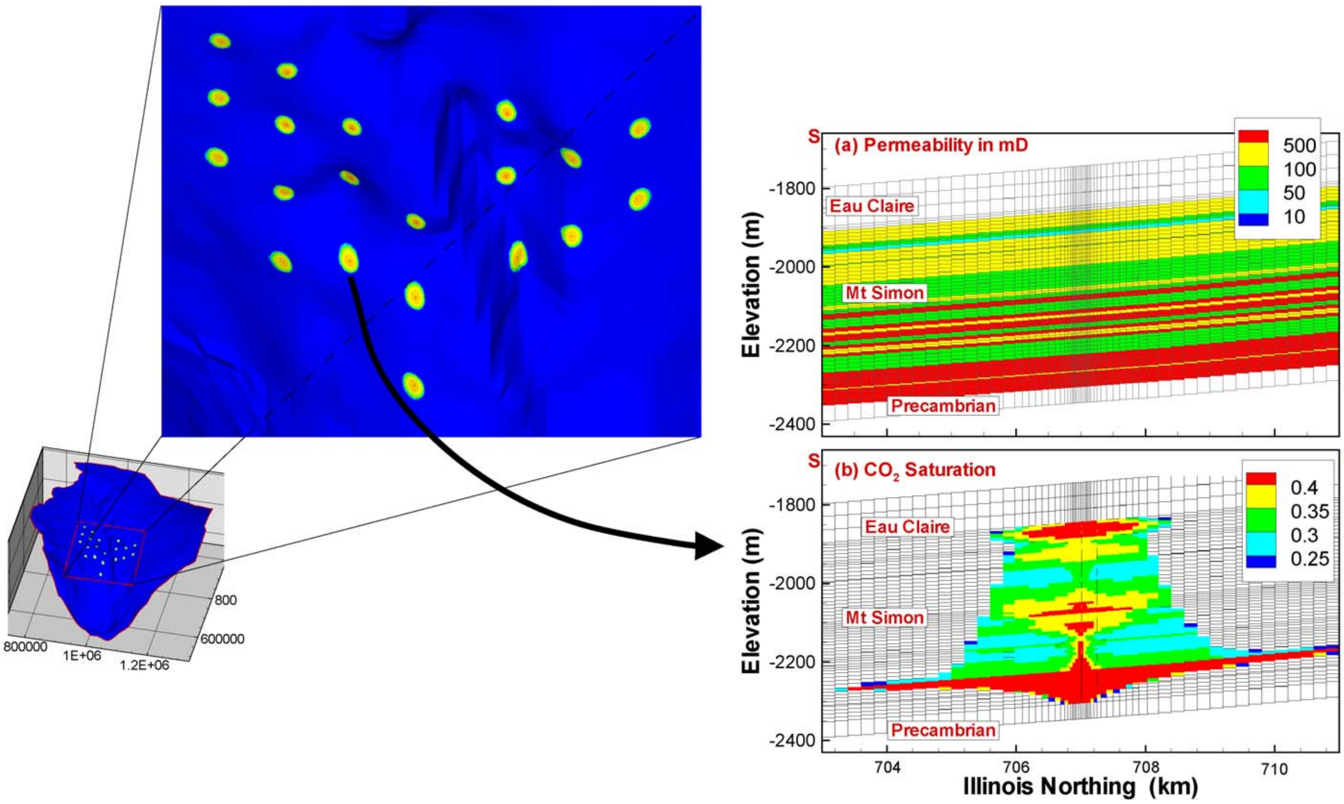

Fig. 3. Graph on left shows contours of CO_2 saturation at 50 years of injection at elevation of maximum plume extent. Graphs on right show (a) vertical permeability field within the Mount Simon Formation (in millidarcy), and (b) CO_2 saturation in a south–north cross section for a selected injection site. The permeabilities assigned to the overlying seal and underlying baserock are 1 and 0.1 microdarcy, respectively.

the area. On the basis of these profiles, an equilibrium (or hydrostatic) condition was simulated, and the resulting distributions of pressure, salinity, and temperature were used as initial conditions for the prediction of the basin-scale environmental impacts of CO_2 injection and storage.

Fixed pressure, temperature, and salinity conditions were defined at the lateral model boundaries (first-type Dirichlet conditions). As mentioned before, the Mount Simon Formation continues to be present beyond the Illinois Basin, allowing brine to escape laterally into neighboring basins further north, west, and east. Since the expected pressure changes caused by CO_2 injection in the basin center are rather small at the model boundaries, we were able to restrict the model to the domain shown in Fig. 1 and define the first-type boundary conditions at the interface with neighboring basins. The effect of other types of lateral boundary conditions (e.g., closed-boundary conditions, infinite-acting aquifer boundary condition) is evaluated in Section 2.2.

The boundary conditions chosen for the top and the bottom of the model domain also deserve some discussion. To reduce the computational load, the model domain comprises only the Mount Simon Formation, the Eau Claire caprock, and the weathered portion of the granite baserock; the overlying sequence of aquifers and aquitards above the primary seal is not included in the model. Since we were interested in an upper-bound estimate of diffuse brine migration from the storage formation through the seal into overlying units, we handled the top of the Eau Claire caprock with a Dirichlet boundary condition assigning fixed pressure, temperature, and salinity values, thereby allowing displaced brine to flow upward and out of the model domain into the overlying sequence of layers, which provide secondary storage space. As discussed in Section 2.2 below, the simulation case with seal permeability of 1 microdarcy represents conditions where diffuse vertical brine migration can significantly attenuate pressure buildup in the storage formation, while the alternative simulation case with 0.01 microdarcy is virtually identical to a case with a closed top-boundary behavior. The bottom boundary underlying the weathered portion of the granite is assumed to be impermeable in all simulation cases.

2.2. Model results

Illustrative model results showing the characteristics of individual CO_2 plumes after 50 years of continuous injection are presented in Fig. 3. CO_2 is injected into an arkosic unit of high permeability and porosity present in the deep parts of the Mount Simon. This ensures sufficient injectivity, and takes advantage of the intervening shale-sandstone sequences of the Mount Simon, which help retard upward migration of CO_2. The maximum size of CO_2 plumes, on the order of 6–8 km, is smaller than the lateral separation of about 30 km between different injection sites, suggesting that merging of plumes would only occur after very long times, if at all.

The close-up view in the vertical cross section highlights the variability of CO_2 saturation and how it relates to the internal layering and permeability differences within the Mount Simon. In addition to the local heterogeneity structure, the shape of CO_2 plumes is affected by the thickness of the Mount Simon and the slope of the structural surfaces, while pressure interference from neighboring injection sites has little effect on overall plume shape (evident from evaluation of center plumes versus edge plumes, not shown here). The details of CO_2 saturation in Fig. 3 emphasize the importance of local mesh refinement to resolve smaller-scale processes, such as structural trapping from internal layering. Overall, our modeling results suggest favorable conditions for safe storage and effective trapping of CO_2, including the thick arkosic unit of high porosity and permeability with sufficient injectivity at

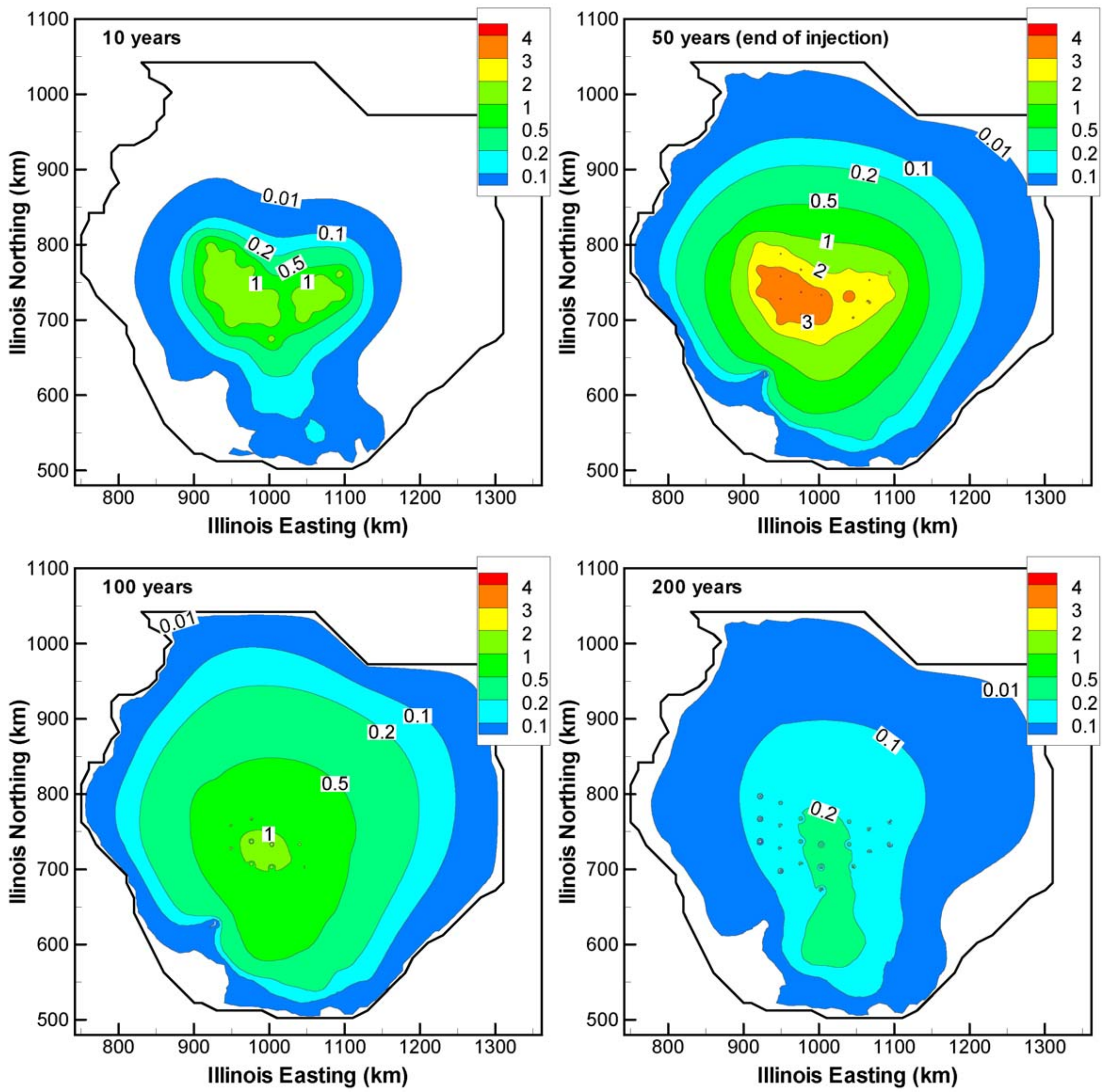

Fig. 4. Contours of pressure increase (in MPa) at the top of the Mount Simon Sandstone at 10 and 50 years (after start of injection) during the 50-year injection period, and 100 and 200 years during the post-injection period. The pressure cut-off value is 0.01 MPa (i.e., pressure buildup below 0.01 MPa is not colored).

the bottom of the Mt. Simon, extensive layering with shaly and sandy deposits in the middle and upper portions of the Mt. Simon, and a thick, low-permeability Eau Claire seal for long-term structural trapping.

Fig. 4 shows the simulated pressure buildup (in MPa) at the top of the Mount Simon at 10, 50 (end of injection period), 100, and 200 years after start of injection. After 10 years, a continuous region with pressure increases of 1 MPa or more has evolved in the core injection area, indicating strong pressure interference between different storage sites located at distances of 30 km or more. After 50 years of injection (i.e., after injection of 5000 Mt of CO_2), the pressure buildup in the core injection area has increased to between 2 and 3 MPa, with peak values above 4 MPa observed near the injection centers. While this is a considerable pressurization over a large region in the center of the basin (of approximately 24,000 km^2), the pressure increase is less than the regulated maximum value above which fracturing of the formation or the caprock may be expected (see further discussion in Section 3). Geomechanical studies may be necessary to evaluate whether the predicted pressure and stress field changes could lead to reactivation of potentially existing faults in the area (e.g., Rutqvist et al., 2007).

With respect to the far-field impacts of CO_2 injection and storage, however, pressure changes propagate extremely far, as much as 150–200 km beyond the core injection area. Eventually the pressure pulse reaches the boundaries of the model domain and thus affects almost the entire basin model, an area of 241,000 km^2. After 50 years of injection, pressure buildup is on the order of 0.1–0.2 MPa in the northern part of the Illinois Basin where the Ironton-Galesville freshwater aquifer overlies the Eau Claire seal. After CO_2 injection ends, the pressure buildup in the core injection area decreases quickly to moderate values around 0.5–1 MPa. As the strong initial pressure perturbation in the core injection area flattens out, the area affected by moderate pressure changes continues to expand laterally.

In a hypothetical storage formation with closed lateral and vertical boundaries, the additional fluid injected into the storage formation would be accommodated only by the compressibility of the rock medium and the fluids, responding to the pressure buildup caused by injection. If fluids can neither exit through the boundaries of the basin nor are allowed to migrate into over- and underlying units, the storage formation will remain at over-pressure indefinitely even after injection ends. In reality, geologic formations are never fully "closed", meaning that there will always

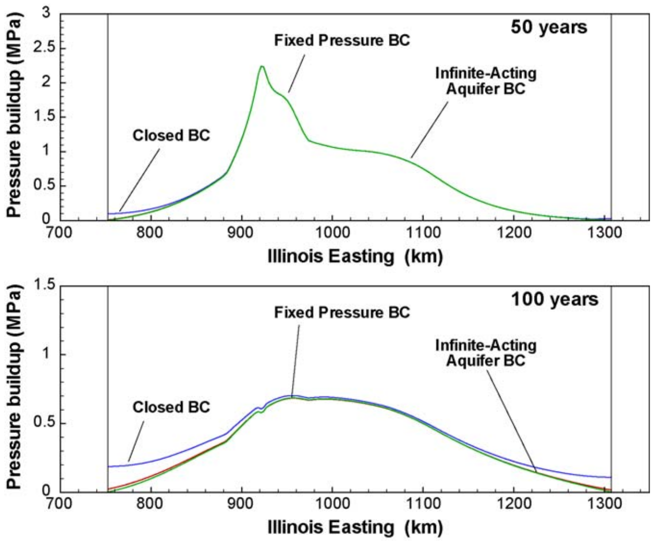

Fig. 5. Profiles of pressure increase (in MPa) along the east–west direction at Illinois Northing of 800 km, for three cases of lateral boundary conditions: a fixed pressure boundary condition (base case, in green), a closed-boundary condition (in blue), and an infinite-acting aquifer boundary condition (in red). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

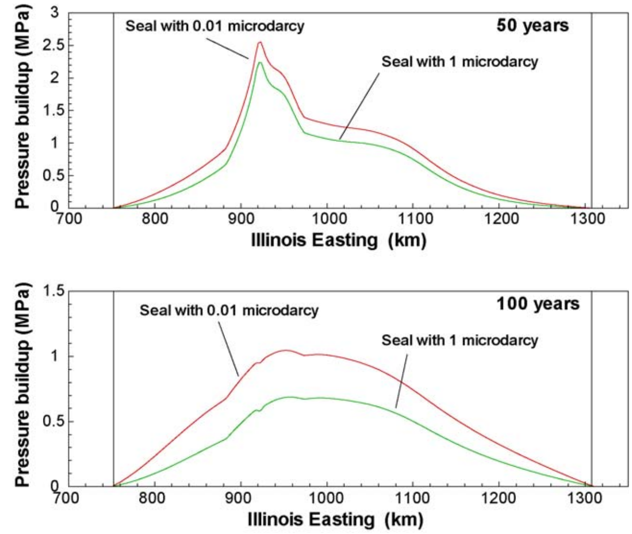

Fig. 6. Profiles of pressure increase (in MPa) along the east–west direction at Illinois Northing of 800 km, for two cases of Eau Claire seal permeability: a permeability value of 1 microdarcy (base case, in green) and a permeability value of 0.01 microdarcy (in red). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of the article.)

be some fluid flow across the boundaries. For example, the sealing units in geologic setting suitable for CO_2 storage have typically very small permeability, but are not impermeable. The same would apply to sealing faults that may laterally confine the subsurface space. Or, as is the case with the Illinois Basin, there is no lateral confinement because the storage formation is hydraulically connected to aquifers in neighboring basins. In such "open" systems, pressurization of the storage formation is temporary. With time, as brine is slowly released at the basin boundaries and through the seals, the system progresses towards a new quasi-equilibrated state and pressures eventually return to hydrostatic conditions (Nicot, 2008). The following discussion elucidates these transient processes for the Illinois Basin example and illustrates the importance of choosing appropriate model boundary conditions.

Fig. 5 shows pressure changes along an east–west profile which runs just north of the core injection area at Illinois Northing of 800 km. Three simulation cases with different lateral boundary conditions are depicted. The first case uses a fixed pressure condition which sets pressure buildup to zero along the boundary (i.e., the base case, as shown in Fig. 4). The second case assumes a closed boundary where no fluids can escape into neighboring basins. The third case utilizes a boundary condition with an infinite-acting aquifer attached to the outer boundary, with grid-blocks extending approximately 200 km beyond the original model domain and their properties and thickness set equal to the Mount Simon at the boundary. This boundary condition provides a simplified method for representing the impacts of neighboring basins, allowing brine to move across the domain boundaries but without forcing pressure buildup to be zero as in the base case. All three simulation cases have virtually identical pressure profiles at the end of the injection period (50 years), with the exception of a small pressure increase observed at the eastern model boundary in the closed-boundary case. The effect of a no-flow boundary condition is more visible at 100 years, where pressure buildup is seen along both the eastern and western model boundary. In contrast, the other two cases are very similar, confirming that the fixed pressure boundary condition assumed in the base case allows for a reasonable representation of the brine release into neighboring basins.

The impact of diffuse brine release in vertical direction, through the primary seal overlying the storage formation, is illustrated in Fig. 6, which shows pressure buildup along the same east–west cross section for two simulation cases: the base case with a seal permeability of 1 microdarcy as well as a sensitivity case with a seal permeability of 0.01 microdarcy. (While results are not shown here, this sensitivity provides pressure results virtually identical to a case with an impermeable seal.) The profiles show clearly the important pressure attenuation caused by vertical brine migration from the storage formation into overlying layers, as pressure values in the lower permeability case are about 10% (50 years) to 50% (100 years) higher than in the base case. These findings are consistent with results from a sensitivity analysis for a multi-layer domain with varying seal permeabilities conducted in Birkholzer et al. (2009). These authors concluded that low-permeability formations suitable for long-term trapping of CO_2 may allow for the egress of large brine volumes out of the storage formation (and correspondingly a considerable pressure mitigation in the storage formation) if the seal permeability is on the order of a microdarcy or higher. It follows that a good understanding of the regional-scale permeability of the confining units is a prerequisite for evaluating the large-scale pressure perturbations generated by CO_2 storage.

Fig. 7 provides a volumetric brine balance for the Illinois Basin model as a function of time, for the base case simulation. The top black line shows the cumulative volume of displaced brine, which is equal to the total volume of injected CO_2 (excluding dissolved CO_2), under storage conditions. This displaced brine volume is in part accommodated by pore and fluid compressibility in response to pressure buildup in the model domain; another part is contributed by brine flow out of the model domain via the lateral and vertical boundaries. The total volume of displaced brine increases almost linearly during the injection period to a maximum value of about 5.2 billion m^3 (5.2 km^3), then reduces slightly as more supercritical CO_2 dissolves. At all times, the total displaced brine volume equals the sum of the (1) compressibility-related pore volume increase and (2) the cumulative brine volume released through the boundaries.

As Fig. 7 suggests, compressibility effects clearly dominate during the injection phase and the early post-injection phase, consistent with the observed pressure trends. Notice that formation compressibility and brine compressibility each contribute about 50% of the total compressibility effect. Brine

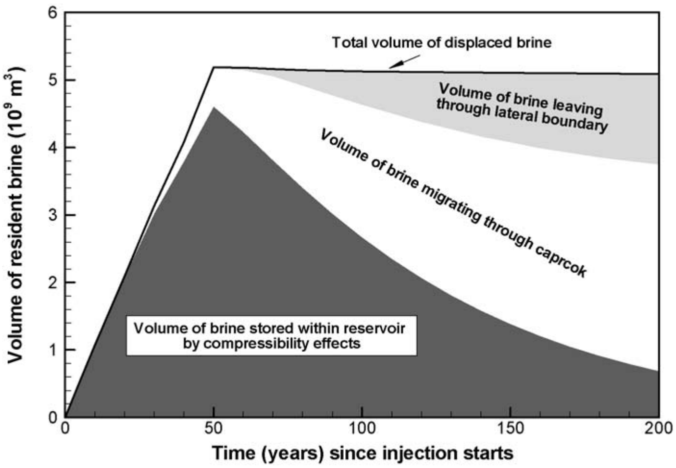

Fig. 7. Evolution of volumetric brine balance for the Illinois Basin model. The top black line shows the cumulative volume of displaced brine, which is equal to the total volume of free-phase CO_2. This displaced brine volume is in part accommodated by pore and fluid compressibility in response to pressure buildup in the model domain; another part is contributed by brine flow out of the model domain via the lateral and vertical boundaries.

compressibility is $3.38 \times 10^{-10}\,Pa^{-1}$ at average pressure and temperature conditions, while the selected pore compressibility is $3.71 \times 10^{-10}\,Pa^{-1}$. Later, as the system slowly progresses towards quasi-equilibrium, compressibility effects become less relevant, while more and more fluids egress from the model domain. At 50 years (the end of the injection period), the cumulative volume of brine released through the boundaries accounts for 9% of the total displaced brine volume; at 200 years, it accounts for 86%. At early times (up to 50 years), brine flow out of the model domain occurs exclusively into the overlying aquifer, as pressure effects have not yet reached the lateral boundaries. At 200 years, 26% of the total brine release occurs laterally into neighboring basins.

The question arises whether the large volumes of brines slowly released from the storage formation have an impact on the hydrogeologic conditions outside of the domain, i.e., in neighboring basins or in the overlying sequence of layers. Notice that these releases across the boundaries have very small vertical and lateral flow rates, typical of natural groundwater flows in deep basins (Birkholzer et al., 2009). These small velocities translate into large fluid volumes of displaced brine only because they occur over very large areas. For example, the Darcy flow velocity across the top model boundary, averaged over the model domain, is only about 0.47 mm/year at 50 years of injection. At the same time, the average Darcy velocity across the lateral boundaries is on the order of 0.2 m/year, with a maximum velocity of 1.2 m/year. The small migration distances of saline water associated with these boundary flows do not constitute a concern for the groundwater resources in overlying aquifers or neighboring basins.

Similarly, the simulated changes in salinity experienced in the model domain as a result of lateral migration and vertical migration of brine are very small, posing no direct threat to groundwater quality (for brevity, salinity changes are not shown in this paper). Salinity issues could become a concern, however, if deep saline water from the Mount Simon was pushed upward into overlying freshwater aquifers via localized pathways, such as conductive faults or open boreholes, which are currently not included in the model. Also not accounted for in the model is the variable sand content in the Eau Claire seal. It was suggested that the Eau Claire seal might have higher sand content (and thus locally higher permeability) in the northern part of the Illinois Basin, which could allow brine to be pushed towards the groundwater pumping wells in the overlying Ironton-Galesville aquifer. Further more targeted studies are needed to evaluate whether the predicted regional-scale pressure change in the Mount Simon pose a threat to local groundwater resources because pressurization may induce localized upward migration of brine.

3. Capacity implications

High-level estimates of regional or global storage capacity for CO_2 sequestration in saline formations have typically been based on simple calculations of the fraction of the total reservoir pore space available for safe storage of CO_2 (Bradshaw et al., 2007; USDOE, 2008). Such capacity assessments start with delineating reservoirs in a basin or region suitable for deep geologic storage (sufficient depth and injectivity), followed by calculating the total storage capacity as a fixed fraction of the reservoir pore volume that can safely be filled with trapped CO_2. In saline formations, the suggested estimates for this fraction, often referred to as the storage efficiency factor, have been on the order of 1–4% (e.g., Koide et al., 1992; van der Meer, 1992; USDOE, 2008). Other researchers have calculated storage potential based on the solubility potential of CO_2 (e.g., Bachu and Adams, 2003). In either way, issues related to pressure buildup or brine migration have not been considered in most regional or global storage estimates, i.e., there is an implicit assumption that the storage capacity is not constrained by pressure buildup and brine migration, and associated impacts on the environment.

As pointed out by Bradshaw et al. (2007), simplistic capacity estimates at the regional or global level can be highly variable and in some instances contradictory, due to the different trapping mechanisms that can occur, and the highly variable nature of geologic settings. These authors suggest that a consistent set of guidelines needs to be developed with clear definitions, rules, and best practices. We strongly agree with Bradshaw et al. (2007), but emphasize the need to base capacity estimates not just on formation suitability with respect to injectivity and trapping of CO_2, but also on the possible basin-scale hydrogeologic impacts caused by adding large volumes of fluids. Our work presented here, as well as recent studies reported in van der Meer and van Wees (2006), van der Meer and Egberts (2008), van der Meer and Yavuz (2008), Zhou et al. (2008), Nicot (2008), and Birkholzer et al. (2009), suggest that environmental concerns related to large-scale pressure buildup may be the limiting factor in carbon dioxide sequestration capacity.

To illustrate the potential impacts of pressure-related capacity constraints, let us compare our hypothetical future injection scenario studied in Section 2 with the current high-level capacity estimates for the Mount Simon, which were based on pore volume considerations. The annual rate of CO_2 injection in our simulation scenario is 100 Mt, about one third of the total CO_2 emissions from current large point sources in the Illinois Basin, and the total injected fluid mass after 50 years is 5000 Mt CO_2. In contrast, the total estimated CO_2 storage capacity for the Mount Simon Sandstone, calculated as a fraction of the total reservoir pore space in suitable parts of the Mount Simon, ranges from 27,000 to 109,000 Mt CO_2 (USDOE, 2008). Thus, the stored CO_2 volume in our simulation scenario corresponds to 18.5% of the lower bound and 4.6% of the upper bound of this range. If CO_2 injection were to continue at the assumed injection rate for a much longer period (or if CO_2 was injected at a higher annual rate), such that the estimated storage capacity was fully utilized, the pressure buildup would be much stronger and extend over a much larger area than seen in Fig. 4. While we have not simulated the expected subsurface conditions for such a full-capacity storage scenario, we believe that storage of 27,000–109,000 Mt of CO_2 in the Illinois Basin would be difficult because of (1) the stronger pressure buildup within the core injection area, which would jeopardize caprock geomechanical integrity, and (2) the stronger pressure buildup and brine migration on the basin scale, which might have environmental impacts on freshwater aquifers in northern Illinois or on neighboring basins.

With respect to caprock integrity, the maximum pressure increase in the current simulation scenario is about 3–4 MPa near the center of individual storage sites, which corresponds to an average fractional pressure buildup, defined as the ratio of pressure increase to pre-injection pressure, of 0.25. (Introduction of additional injection wells at each site may have some local effects, but would not significantly reduce the overall pressure buildup in the core injection area because of the strong interference between individual storage projects.) This value of 0.25 is less than the regulated fractional pressure increase of 0.65 used in the region. If a value of 0.65 (or a maximum pressure buildup of up to 9 MPa) is used and a quasi-linear relationship between injection rate and pressure buildup (Zhou et al., 2009) is considered, the total injection volume assumed in our simulation scenario could be increased from 5000 to 13,000 Mt. However, regulators might be reluctant to allow fluid pressurization of such magnitude over such a large area, or, as mentioned before, smaller threshold pressures may be required if geomechanical studies indicate the potential for reactivation of potentially existing faults.

We may thus conclude that current high-level estimates of regional or global storage capacity in deep saline formations need to be revisited based on the evaluation of pressure buildup and environmental impacts, and we may expect that these estimates would have to be corrected downward in many cases. Because of the complex nature of large-scale hydrogeologic processes, such capacity re-evaluation needs to be site- or basin-specific; it is not conducive to generalization or quick assessment with limited data. It should be noted that pressure-related capacity constraints might be relaxed by creating additional store space in the deep storage reservoirs via brine extraction. The extracted brine could be stored in appropriate overlying/underlying formations, or could be pumped to the surface and desalinized for water supply. While such pressure management schemes can provide a way around capacity limitations, their technical and economic feasibility needs to be evaluated in further studies.

4. Prediction uncertainties

From the standpoint of fluid dynamics, brine pressurization and migration is a much simpler process than two-phase flow of CO_2–brine mixtures. The challenge for predictive modeling is not in fundamental process issues, but rather in obtaining a sufficiently detailed and realistic characterization of large subsurface volumes, in order to be able to place meaningful and reliable limits on quantities and pathways for pressure buildup and brine migration. The propagation of pressure changes in a porous medium is a function of the hydraulic diffusivity D of the formation. Hydraulic diffusivity is defined as the ratio of transmissivity to storativity, given as $D = k/(\beta\phi\mu)$, where k is formation permeability, β is compressibility of both the brine and the pore structure, ϕ is porosity, and μ is dynamic viscosity of the brine. For a given D, the propagation radius R of a pressure wave in a two-dimensional radial system with constant thickness and homogeneous properties can be approximated as $R \approx \sqrt{2Dt}$, where t is the time since injection starts (Nordbotten et al., 2004). We apply this approximate equation below to demonstrate that uncertainties in the key parameters for pressure propagation can strongly affect the extent of the pressure-affected region.

Using the formation properties chosen for the Mount Simon simulation model outside of the core injection zone (see Section 2.1), i.e., k = 500 millidarcy (=5×10^{-13} m^2), $\beta = 7.09 \times 10^{-10}$ Pa^{-1} (which comprises contributions from brine compressibility, 3.38×10^{-10} Pa^{-1}, and pore compressibility, 3.71×10^{-10} Pa^{-1}), $\phi = 0.12$, and $\mu \approx 0.0005$ Pa s, D becomes approximately 11.7 m^2/s. This translates into a pressure propagation radius from the core injection zone of $R \approx 86$ km after 10 years and $R \approx 190$ km after 50 years, which is in reasonable agreement with the model predictions in Fig. 4. A change in hydraulic diffusivity by one order of magnitude, arguably a reasonable uncertainty range for large-scale hydraulic properties, would translate into a change in pressure propagation radius by roughly a factor of three. In other words, if hydraulic diffusivity is smaller by a factor of 10, which could be caused by a smaller permeability, larger compressibility or porosity, or a combination thereof, the extent of the pressure-affected region outside of the core injection area would reduce from 190 km to only 60 km. This makes a considerable difference with respect to the size of the Area of Review that would have to be characterized in the case of multiple-site sequestration in the region.

Additional factors that are not well understood or hard to characterize can further increase uncertainty about large-scale hydrogeologic impacts, for example the possible dampening of pressure propagation across faults, the far-field effect of small-scale and intermediate-scale heterogeneity (e.g., sand-shale interbedding), or the possibility of pressure relaxation by brine flow into overlying and underlying units. Notice also that the approximate propagation distance calculated above is not a measure of the possible magnitude of the pressure perturbation. While a decrease in permeability and an increase in compressibility have the same effect on propagation distance, the magnitude and spatial distribution of pressure changes would be very different. A smaller permeability value causes less far-field pressurization, but higher pressure buildup in the core injection area, possibly up to the point that injectivity or geomechanical damage may become a concern. While a higher compressibility value also causes less far-field pressurization, the pressure buildup in the core injection area would be reduced as well, as more storage volume per unit volume of rock is created from the same overpressure.

It is clear that a comprehensive site characterization and data review of deep saline formations on the basin scale are needed to allow for reliable prediction of regional brine pressurization and migration; the extent, geology, hydrology, and hydraulic connectivity of deep hydrogeologic systems need to be well understood. It is also obvious that large CO_2 storage field experiments, such as the deployment phase tests soon to start in the United States (NETL, 2009), can be very useful for better understanding and constraining the processes and parameters driving brine pressurization. We strongly recommend making measurements of far-field brine pressurization a significant component of the monitoring strategy in these tests. However, the storage volumes achievable in such experiments, likely close to one million metric tonnes, may still be too small to allow extrapolation to the basin or regional scale. Possibly the best analog for an industrial-scale carbon storage project is the industrial-scale carbon storage project itself. In other words, the pressure monitoring conducted in the early phase of a industrial-scale project can provide valuable data for further pressure impacts during later project stages; these data would feed into periodic re-evaluation with improved prediction models. Similarly, in a basin with multiple storage sites, data from early projects can help to reliably estimate the expected pressure impact from later projects.

5. Implications for the evolving regulatory framework in the United States

While the regulatory environment for geologic carbon sequestration projects is still evolving, it is clear that one aspect of permitting is the protection of valuable groundwater resources.

Since groundwater quality can be affected by intrusion of CO_2 as well as by brine intrusion, the permitting requirements will need to include some assessment of CO_2 leakage risk as well as some assessment of large-scale pressure buildup and associated potential for brine migration. The United States Environmental Protection Agency (USEPA) has recently developed a draft regulation for geologic carbon sequestration under the Safe Drinking Water Act (SDWA), with its main focus being the protection of underground sources of drinking water from injection-related activities (USEPA, 2008). Most elements of the proposed rule are based on the existing framework of the Underground Injection Control (UIC) program, which regulates injection of hazardous and non-hazardous fluids, injection related to oil and gas production, injection related to solution mining operations, and some other types of injection operations.

USEPA requires in its proposed rule that an Area of Review is defined in which all penetrations intersecting the injection formation and confining units must be identified. The purpose is to determine the presence of features such as faults, fractures, and artificial penetrations, through which significant amounts of injected fluid could move into freshwater aquifers or displace native fluids into freshwater aquifers. It is acknowledged in the draft rule that "the CO_2 plume and pressure front associated with a full-scale geologic sequestration project will be much larger than for other types of UIC operations, potentially encompassing many square miles ... It is also possible that multiple owners or operators will be injecting CO_2 into formations that are hydraulically connected, and thus the elevated pressure may intersect or interfere with each other". USEPA thus realizes that an Area of Review (1) can be extremely large and (2) is likely to be affected by intersecting pressure perturbations in a multiple-site scenario.

The example predictions of basin-wide pressure buildup illustrated in Fig. 4 clearly demonstrate the two points made above. Assuming that a threshold value of pressure increase can be defined to delineate the Area of Review and using reasonable thresholds of about 0.5 and 0.05 MPa (the basis of which will be discussed later in this paper), the Area of Review in our Illinois Basin sequestration scenario would encompass the entire center region of the basin, roughly 300 km by 300 km (for 0.5 MPa at 50 years) and 500 km by 500 km (0.05 MPa at 50 years), respectively. In other words, areas exceeding 100,000 km^2 would have to be characterized for conductive features and artificial penetrations would have to be tested for proper completion and plugging. This task would likely exceed the capacity and willingness of any single operator in the basin. Additional complexity arises as the large Area of Review would be the composite result of many storage sites operating simultaneously. Owners or operators would likely point out that their individual contribution to the Area of Review extent is only a fraction of the composite Area of Review.

The question arises as to how these regional impacts of geologic sequestration with multiple storage sites in a given basin can be effectively regulated. One possibility could be to regulate under a "first come, first serve" principle, where early applicants in a basin would have the advantage of delineating their Area of Review without consideration of other possible storage operations. Later applicants would have to develop their permitting case under consideration of the pressure impacts of all ongoing or approved operations in the region. The Area of Review for these applicants would be defined by the additional pressure increase expected from the new storage project, determination of which is not an easy task for an applicant because current and future impacts from all other operation need to be known. Also, later applicants might have higher operational costs because they may need to inject into a pressurized formation. The "first come, first serve" principle would favor early projects, a possible incentive for accelerated implementation of carbon capture and storage.

An alternative, more coordinated approach to regulating basin-scale multiple-site CO_2 sequestration is the hierarchical permitting model recently proposed by Nicot and Duncan (2008). These authors suggest two permitting levels: The first level (referred to as general permit) would involve an overarching federal or state agency to develop regional assessments of large brine reservoirs with the goal of characterizing them to the point that they are "sequestration ready". The second level would involve permit applications for individual sites, with the expectation that (1) the burden faced by an applicant would be less because regional assessments have already been conducted, and (2) the permitting process for each site would be reviewed under the umbrella of a coordinated regional permit.

Expanding on Nicot and Duncan (2008), we suggest a general permit should handle all Area of Review tasks related to far-field pressure change and brine migration, while a single-site permit would focus on the local area near the projected site, including the area of the CO_2 plume and some yet-to-be-defined area beyond the plume extent where pressure impacts are highest. In our Illinois Basin example, individual applicants might be focusing on the core injection area shown in Fig. 1, while the responsible agency for a regional permit would conduct the necessary characterization and corrective action (e.g., plugging of improperly completed wells) activities outside of this core area. The responsible agency would also (1) oversee efforts to build reliable basin-scale simulation models for the region, (2) predict the large-scale hydrogeologic impacts for possible future sequestration scenarios in the region, (3) define the size of the Area of Review, and (4) estimate the maximum storage capacity in the basin based on the projected environmental impacts. The simulation model would be periodically re-evaluated as more storage projects go online and more monitoring data become available. Based on model predictions, new site applications would be evaluated and coordinated in the context of other existing and planned operations.

Of crucial importance for permitting of large storage projects is the question as to how the size of an Area of Review should be determined, in particular with respect to the hydrogeologic consequences of large-scale pressure buildup and possible brine migration into groundwater resources. While there is a general consensus that the region of maximum future CO_2 plume extent needs to be well characterized, it is not clear at present how to handle the much larger region of pressure impact in a site evaluation process. Can the size of an Area of Review be determined based on a threshold value of pressure buildup and, if so, how can this value be determined? While the draft regulation introduced by USEPA currently provides no guidance on this matter, one possible approach could be based on the existing framework of the Underground Injection Control (UIC) program. There, the Area of Review is computed as the region where the pressure increase experienced at any time would be able to lift saline formation water through a potentially existing open borehole to the bottom of an overlying freshwater aquifer. Because the brine being pushed upward has a higher density than the borehole fluid it displaces, upward migration of brine can only be sustained when the pressure increase in the formation exceeds a minimum value, which is mostly determined by the vertical distance and the initial density profile in the borehole. Nicot et al. (2008b) presented a method for calculating this minimum value and applied it to case studies from a site in the Central Valley in California and two sites in the Texas Gulf Coast region. Pressure threshold values ranged from 0.058 MPa for the Central Valley case up to 0.56 MPa for the Texas Gulf Coast cases, the difference mostly caused by the much higher salinity of the deep brines in the latter examples. The calculations assume that the pressure profiles are initially hydrostatic, a condition that may or may not be appropriate.

One may express concern that Area of Review estimates based on the potential existence of completely unplugged boreholes may be too conservative, particularly in regions not or not strongly affected by a long history of oil and gas exploration. Such estimates can be extremely large, as would be the case in our Illinois Basin example. Depending on the site conditions, other conduits for brine migration into freshwater aquifers may be more relevant, such as conductive faults or other caprock imperfections. In the Illinois Basin, the relatively few deep boreholes penetrating down to the Mount Simon Formation may not pose a threat at all as they are likely to be properly plugged, whereas a possibly higher permeability of the Eau Claire seal in the northern part of the basin could allow brine to be pushed towards the groundwater pumping wells in the overlying Ironton-Galesville aquifer. We believe that the size of an Area of Review cannot be determined from a generic one-size-fits-all approach. Rather, the detailed basin- and site-specific conditions, and the vulnerabilities of potential environmental receptors to brine migration, need to be accounted for in any Area of Review definition. We also believe that the site characterization requirements for the region of maximum future CO_2 plume extent would be different from (and likely more stringent than) the requirements imposed on characterizing the much larger region of pressure impact, as the driving forces for CO_2 leakage versus brine migration are different, and so may be the possible environmental impacts.

6. Summary and conclusions

We evaluated regional-scale brine pressurization and migration related to a hypothetical future carbon sequestration scenario in the Illinois Basin in the midwest United States. The area hosts a significant number of large stationary CO_2 emitters and will be one of the most important regions for geologic storage of carbon dioxide in the United States. A regional-scale 3-D simulation model was developed for the Illinois Basin to capture both the local-scale CO_2–brine flow processes and the large-scale groundwater flow patterns in response to CO_2 storage. We assumed in our simulations that each of the twenty individual storage projects spread out in the center of the basin will inject 5 Mt of CO_2 annually over a time period of 50 years. The total annual injection mass of 100 Mt corresponds to roughly one third of the current annual CO_2 emissions from stationary sources in the area. The target reservoir for storage is the Mount Simon Sandstone, a very extended saline formation of good permeability and porosity, and sufficient thickness, with proven seals.

Our predictions demonstrate that multiple-site storage in the Mount Simon will result in a large continuous region with overpressure, in which the pressure perturbations from one storage site strongly interfere with other storage sites. With respect to far-field impacts, pressure changes may propagate as far as 200 km from the core injection area hosting the 20 storage sites. While this pressure buildup and associated brine migration is not likely to impact neighboring basins, the potential of hydrogeologic and geochemical changes in the overlying groundwater regimes requires further evaluation. For example, salinity issues could become a concern if brackish water from the Mount Simon is pushed upward into overlying freshwater aquifers via possibly existing localized pathways, such as conductive faults or open boreholes.

While recognizing considerable uncertainty in our predictive model, we used the Illinois Basin study as an illustrative example to discuss some of the implications related to multiple-site CO_2 sequestration in deep saline formations. Our main conclusions and recommendations are listed below:

- In deep saline formations, geomechanical and environmental concerns related to large-scale pressure buildup may be the limiting factor for sequestration capacity. We believe that current estimates of storage capacity, which are typically based on the effective pore volume available for safe trapping of CO_2, need to be revisited on the basis of site- or basin-specific assessments of pressure buildup and their potential impacts on freshwater aquifers. Creative pressure management schemes via brine extraction (and subsequent re-injection into other formations, or desalinization and use for water supply) could provide an engineering solution in cases where storage capacity is limited by pressure buildup, but further studies on feasibility and economics are necessary.
- Considering the importance of large-scale predictions of hydrogeologic impacts in response to CO_2 storage, we recognize the usefulness of upcoming large field tests for better understanding the relevant processes and parameters and reducing prediction uncertainty. Far-field measurements of brine pressurization should be included, as an important monitoring component, in these tests.
- Understanding the large-scale pressure buildup and brine migration patterns is extremely important for regulating CO_2 storage projects, in particular when multiple storage sites are hosted in a sedimentary basin with interconnected reservoirs. In such cases, pressure interference between individual sites will require appropriate and effective permitting approaches. Two suggestions are made in this paper, one using a "first come, first serve" principle, the other following Nicot and Duncan's (2008) proposed hierarchical approach with a general permit for a region and site-specific permits for individual projects.
- Considering the extent of pressure propagation observed in our study, the area that needs to be characterized in a permitting process (referred to as the Area of Review in the new United States draft regulation proposed by USEPA) could comprise an extremely large region. The question as to how to define the size of the Area of Review with respect to large-scale hydrogeologic consequences will thus be of critical importance. We believe that a one-size-fits-all approach, e.g., defining a general fixed-value pressure threshold, will not work; rather we suggest basing the Area of Review size on the detailed basin-scale conditions and the vulnerabilities of potential environmental receptors. Within the Area of Review, the site characterization requirements for the region of maximum CO_2 plume extent should be higher than those for characterizing the much larger region of pressure impact.
- Further research is needed to evaluate the possible consequences of far-field pressurization on groundwater resources, i.e., evaluating the potential for and magnitude of upward brine migration via possibly existing localized pathways, such as conductive faults or open boreholes, or analyzing the water quality changes in response to brine intrusion into freshwater aquifers.

It is important to assess (and regulate) the potential environmental impacts of GCS in the context of other anthropogenic influences affecting our groundwater resources. For example, excessive pumping of groundwater resources for municipal water supply and agricultural uses has caused widespread aquifer drawdown and salinity increases in many areas in the United States. In the Chicago metropolitan area, heavy groundwater pumping in northern Illinois induced drawdown of up to 250 m during the second half of the last century, eventually pulling deeper saline waters towards some withdrawal wells. These impacts dwarf the predicted environmental consequences of the hypothetical CO_2 storage scenario studied in this paper. One also needs to weigh the environmental impacts of GCS against the regional and global benefits of mitigating climate change. In other words, one needs to consider the potential environmental, socioeconomic, political, and also hydrogeological consequences of continued CO_2 emissions in a business-as-usual climate scenario.

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